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QUANTITATIVE METHODS FOR RESERVOIR CHARACTERIZATION AND IMPROVED RECOVERY: APPLICATION TO HEAVY OIL SANDS

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Abstract

Improved prediction of interwell reservoir heterogeneity is needed to increase productivity and to reduce recovery cost for California's heavy oil sands, which contain approximately 2.3 billion barrels of remaining reserves in the Temblor Formation and in other formations of the San Joaquin Valley. This investigation involves application of advanced analytical property-distribution methods conditioned to continuous outcrop control for improved reservoir characterization and simulation. The proposed investigation is being performed in collaboration with Chevron Production Company U.S.A. as an industrial partner, and incorporates data from the Temblor Formation in Chevron's West Coalinga Field.

A portion of Section 36 of West Coalinga Field was selected as the site to conduct a comparison of geologic and fractal models with results from an ongoing steam flood. The layer structure and permeability distributions of the different models were incorporated into a numerical flow simulator. The modeling objectives with regard to facies tract and facies group models have been achieved, with satisfactory matches for the oil and water production. The injection and production histories, including shutdowns, of the wells in the study area were accurately modeled, including the occasional conversion of production wells to steam injection wells. An exhaustive sensitivity analysis was performed to determine which reservoir and fluid properties have the greatest control on oil and water production. These results indicate that predictions of oil production are strongly influenced by the geologic framework and by the boundary conditions. The framework provided by facies groups provides a more realistic representation of the reservoir conditions than facies tracts, which is revealed by a comparison of the history matching for the oil production.

Numerical difficulties encountered during multi-phase flow between cells with large permeability differences have created challenges in simulation using the fractal permeability distribution. This impediment is currently being addressed by the use of a new matrix solver for the numerical flow simulator, as well as modifications to the fractal field.

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Methods

The geologic architecture of facies tract and facies group models was successfully integrated into the grid structure of the numerical flow simulator, T2VOC (Falta et al., 1995). T2VOC is capable of modeling multiphase, multi-component, non-isothermal flow and was developed at the Lawrence Berkeley Laboratory in California. This simulator has been used extensively by government agencies and private corporations to model the flow of water, air, steam, and oil in multi-dimensional, heterogeneous porous media.

A five-year period, October 1995 to October 2000, was chosen to compare the simulated rates to field production. The starting date corresponded to the commencement of the steam flood in the modeled area. After this time period, a horizontal production well was installed through the study area and the overall flow regime was altered.

During the simulation period, the injection and extraction histories for the wells in the study area varied greatly. The steam volume of the injection wells changed monthly, and many of the injection wells did not come online until 1997 or later. The production wells were regularly shut down for maintenance, or were converted into steam injection wells for a few months before being turned back into production wells. All of these changes in production and injection were incorporated in the setup of the flow simulator.

In the flow simulator, the production wells were constructed using a productivity index, where production occurs against a prescribed flowing wellbore pressure. This condition means that very little oil or water production will occur until the pressure gradient generated by the steam injection is conveyed to the producing wells.

The early simulations showed that the model was producing too much water, and too little oil, when compared with the field results. This initiated an exhaustive sensitivity study to determine the contributing factors. The parameter with the greatest influence on the water production was the endpoint of the relative permeability curve for the water phase in an oil-water mixture. The oil production was controlled both by this parameter and by the initial oil saturation.

The change in the endpoint for the water relative permeability is shown in Figure 1. The endpoint for the water relative permeability curve at 100% water saturation was lowered from 0.56 (reported by Chevron) to 0.15. The change in this parameter can be justified in several ways. Relative permeability data are generally derived from testing a limited section of core, typically the major oil producing zone. Applying this value to all the rock units in the simulated grid is not realistic. Further justification comes from a modeling study of steam injection into the Midway-Sunset field in the San Joaquin Basin (Hazlett et al., 1997) where a similar reduction in the endpoint for water relative permeability was used. Also, the overall oil saturations were increased by 20% over values calculated by Chevron from the borehole geophysical logs. As these data were obtained from a few wells over a large area, with the data acquired at different times during the production history, it was felt that this increase was justified.

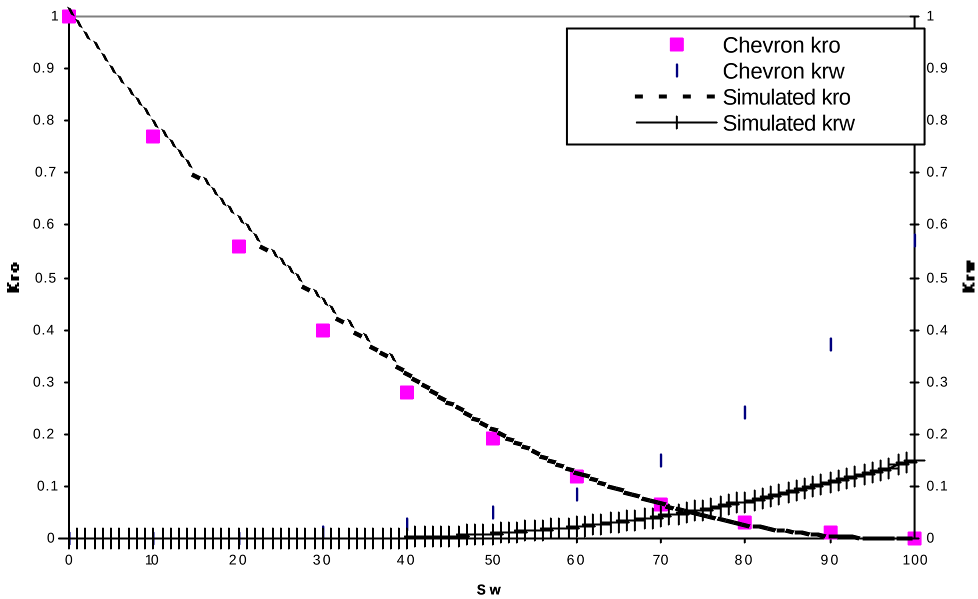

Figure 1: Oil-water relative permeability curve showing change in the water relative permeability curve endpoint where Sw=100%.

Results and Discussion

A comparison of oil production from flow simulation using the facies tract and facies group models with the field production is shown in Figure 2. As there are numerous production wells, only the combined production from all the wells is presented. This figure illustrates that, in general, a better match of oil production is obtained from the facies group model than from the facies tract model.

Both models match the oil production up to about one and a half years. This point in time corresponds to a peak in the amount of steam injected into the field during the five-year period, as shown in Figure 3. The over prediction of oil production by the facies tract model at this point can be attributed to its relatively homogenous nature. The large increase in steam injection that occurred at this time created a strong pressure wave that moved quickly through the facies tract model, dramatically increasing production. On the other hand, the pressure wave was absorbed and somewhat dissipated by the higher degree of stratification and permeability contrasts contained within the facies group model. This allows for a much better match of the field production.

After one and a half years, the steam injection rate becomes more consistent. Both models simulate the oil production from 1.5 to 2.5 years fairly well, but then the results vary. At around 2.5 years, the facies tract model begins to over predict the oil production, and the facies group model slightly under predicts it. This can be explained

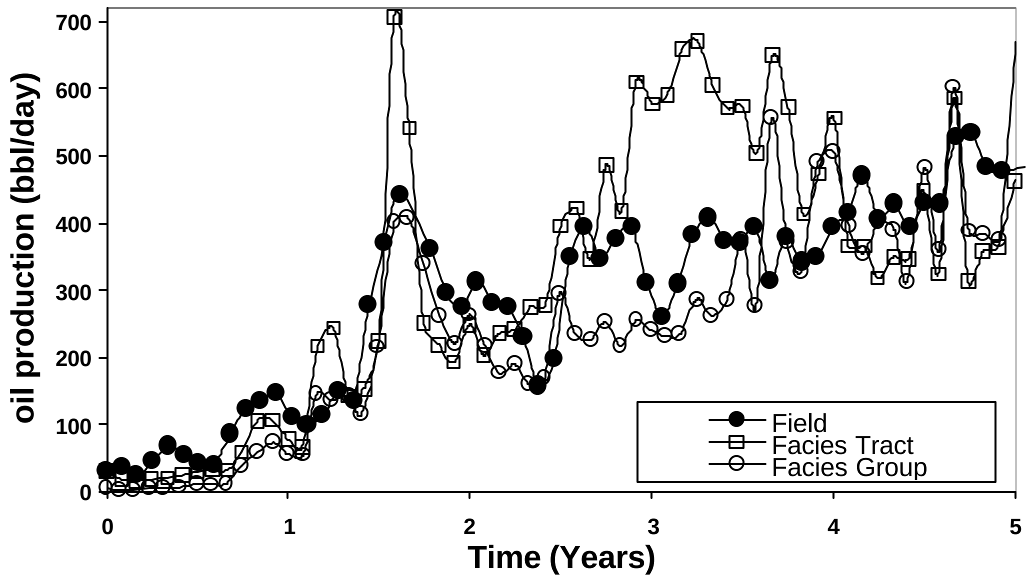

Figure 2: Comparison of oil production from the facies tract and facies group geologic models with the field production.

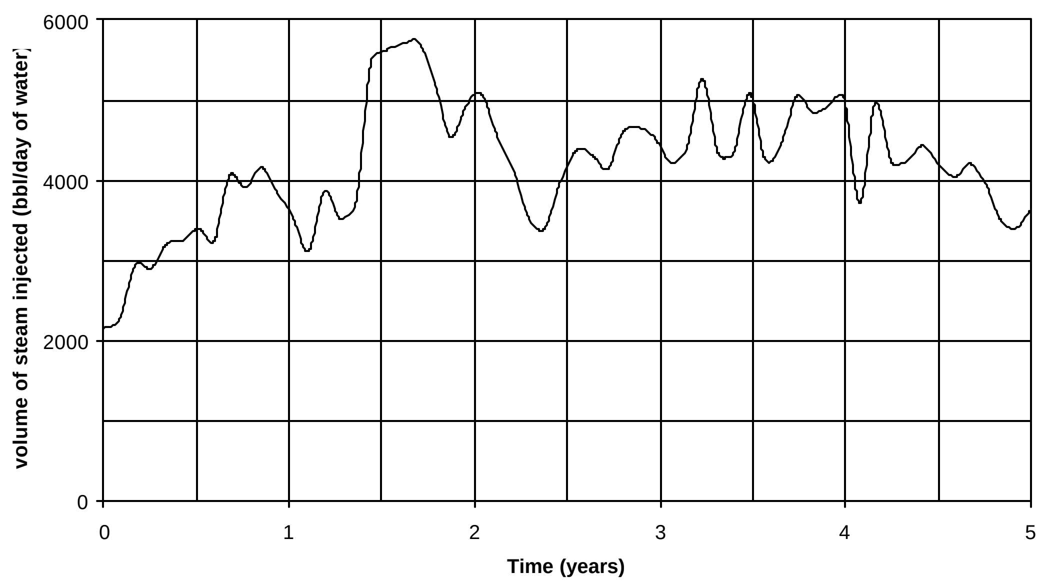

Figure 3: Combined steam injection from all wells in the study area.

by the nature of the no-flow boundaries and the homogenous character of the facies tract model. These two conditions create a situation where the grid cells on the updip side of the model (the west side) become over pressured, and thus produce oil at an abnormally high rate. The reason the updip cells are being affected is that the steam front moves upgradient, and the relatively homogenous nature of the facies tract models does not readily impede the steam front. The facies group model slows down the steam front, apparently a little bit too much, as this model slightly under predicts oil production in this time period.

As the injection pressure falls off after 4 years, both models exhibit good matches of the oil production. In the case of the facies tract model, the match is probably due to the reduction in pressure. For the facies group model, the match is attributed to the pressure front created by the delayed steam front reaching the production wells.

A comparison of the water production for the facies tract and facies group models is illustrated in Figure 4. As shown, both models over predict the amount of water produced. This is most likely the result of improper boundary conditions on the down dip eastern side. Usually, no flow boundaries are an appropriate assumption for a five-spot production/injection setup, but the results indicate that a constant head boundary may be more appropriate. The simulated water production is comparable to the quantity of water being injected, but the field production of water is much lower. This indicates that some of the water is being lost to the formation outside the study area.

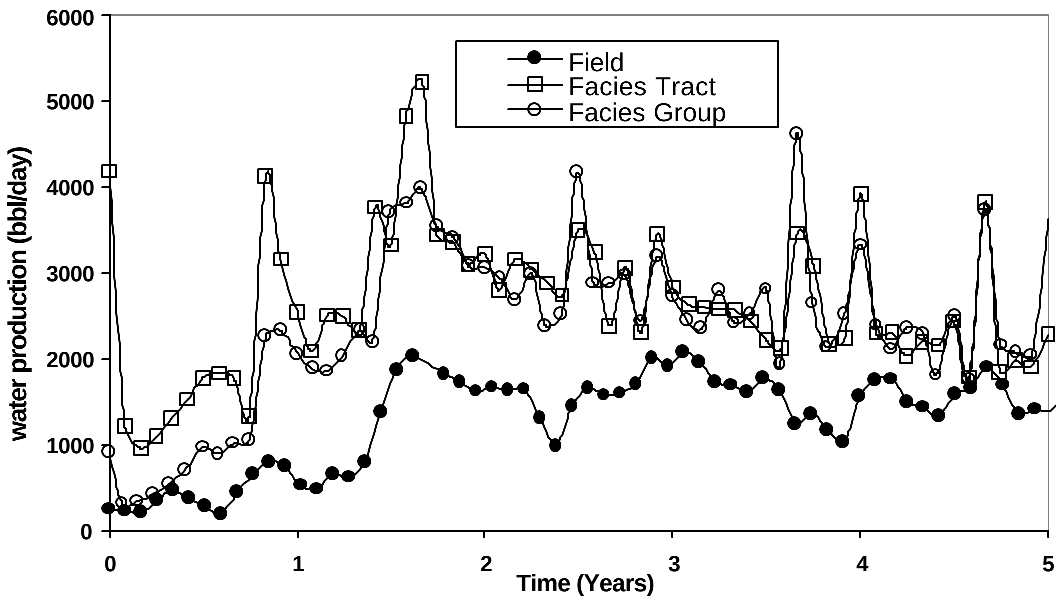

Figure 4: Comparison of water production from the facies tract and facies group geologic models with the field production.

The simulation results were presented at the annual national meeting of the American Association of Petroleum Geologists in March (Fawumi et al., 2002).

Conclusions

The modeling objectives with regard to the facies tract and facies group models have been achieved. The complicated injection and production well histories, including shutdowns, of the wells in the study area were accurately modeled, including the occasional conversion of production wells to steam injection wells. An exhaustive sensitivity analysis was performed to determine which reservoir and fluid properties have the greatest control on oil and water production. The sensitivity analysis revealed that lowering the endpoint for the water relative permeability curve had the greatest effect on decreasing water production, and that increasing the oil saturation had the greatest effect on increasing oil production. Satisfactory matches for the oil and water production were obtained.

Our results indicate that predictions of oil production are strongly influenced by the geologic framework and by the boundary conditions. The framework provided by using facies groups provides a more realistic representation of the reservoir conditions than using facies tracts, which is revealed by a comparison of the history matching for the oil production. It is anticipated that altering the boundary conditions will generate a better match for the water production.

In the fractal permeability distribution model, numerical difficulties involved with multiphase fluid flow between cells with large permeability differences has created challenges in simulation. This is currently being addressed by the use of a new matrix solver for the numerical flow simulator, as well as modifications to the fractal field.

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